The Innes Field, Block 30/24, UK North Sea

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Abstract

The abandoned Innes Field was wholly within Block 30/24 on the western margin of the Central Trough in the UK sector of the North Sea. Hamilton Brothers Oil Company operated the exploration and production license and Innes was the third commercially viable oil discovery in the block after Argyll and Duncan. Discovery of the field was made in 1983 with well 30/24-24. Three appraisal wells were drilled one of which was successful. Oil was found in the Lower Permian Rotliegend sandstones sealed by Zechstein dolomites and Upper Jurassic shale.

The discovery well and the successful appraisal well were used for production. Export of the light, gas rich crude was via a 15km pipeline to the Argyll hub. Innes Field was produced via pressure decline with no secondary recovery attempted. The field was abandoned in 1992 having produced 5.8 mmbbl of oil and possibly 9.8 bcf of gas. At most the water cut was a few percent.

The field was reexamined between 2001 and 2003 by the Tuscan Energy/Acorn Oil and Gas partnership with a view to tying the field back to the newly

redeveloped Argyll (Ardmore) Field but marginal economics and financial constraints for the two start-up companies prevented any further activity on Innes. Enquest currently owns the license and the company has redeveloped Argyll, as Alma, for a second time. There are presently no plans to drill again on the Innes Field.

Introduction

Hamilton Brothers Oil Company (HOC) was one of the most successful companies to operate in the North Sea and adjacent areas during its first quarter century of exploration and production. By the time HOC was acquired by BHP in March 1991, the company had made 13 significant discoveries (OGA, 2016) most of which were in production, with the remaining few producing within a few years of the BHP acquisition. The Innes Field was the third oil discovery on a license which covered all of Block 30/24 and part of Block 30/25a.

The first discovery was well 30/24-2 drilled in 1971. It became the Argyll Field, although this discovery was nearly missed (Figure 1). Well 30/24-1 had been drilled on the same structure and only when the well abandonment was complete was the first well recognized to be an oil discovery. Oil was flowed from Permian Zechstein carbonates and several intervals in what was thought at the time to be Permian Rotliegend sandstones. Only later was this shown to be a combination of Permian Rotliegend and older Devonian red beds. Later wells on Argyll flowed oil from Jurassic (Fulmar) sandstones and oil was proven though not flowed from the Cretaceous Chalk. The second discovery on Block 30/24 was made with 30/24-15 (named Duncan, 1981) a few kilometers west of Argyll.

It found oil in the Upper Jurassic Fulmar sandstones but both the Zechstein and Rotliegend intervals were dry. Innes (1983) with a Rotliegend reservoir was the third discovery and the fourth and final discovery in the license was made by well 30/25a-4 (1988). It tested at 600 bopd also from a Rotliegend sandstone. This final discovery was not developed and never listed as significant.

History of Exploration and Appraisal

The Innes Field was discovered in 1983 by well 30/24-24 (Figure 2). It is located about 13 km north-west of Argyll. A total of four wells were drilled on Innes of which two (30/24-24 and 30/24-32) found oil and two were classified as water saturated (30/24-27 and 30/24-35). In fact neither well was truly dry; 30/24-27 had a residual oil column in the Rotliegend and oil shows were recorded from the Chalk of 30/24-35. Indeed, the Jurassic Fulmar sandstone above Innes also had oil shows. An additional well (30/24-36) was drilled on a separate structure, about 2 km north-east of Innes, however this was also water saturated at the Rotliegend level with a short oil column in the Fulmar sandstone. Innes was produced through two subsea wells (30/24-24 and 30/24–32) tied back to Argyll.

The discovery well, 30/24-24, tested dry oil from Rotliegend sandstones at 12,260 – 12,400 ftMD. Later that year (October 1983) the appraisal well 30/24-27 was drilled about 1.5 km east of the discovery well. Well 30/24-27 found almost 300 ft of Rotliegend sandstones, however the entire section was essentially water saturated. As noted above, the core from 30/24-27 is oil stained throughout and shows a dull yellow fluorescence on the original uv core photographs. This was not reported at the time.

The oil-stained core from 30/24-27 well contrasts with that from discovery well 30/24-24 that shows no obvious oil staining and at most weak whitish fluorescence. The contrasts in oil staining and uv fluorescence between wells 24 and 27 is taken to indicate that the Innes trap has changed geometry through geological time and has had two oil charges. The area penetrated by well 27 received an oil charge first, consisting of yellow-fluorescing medium gravity oil. This oil was lost leaving the reservoir stained. A second charge of light, pale white-fluorescing oil then migrated into the area penetrated by well 24 and it is this oil which now forms the Innes Field. That the current oil charge in Innes and the earlier accumulation, inferred from the staining of the core in well 27, are in different places indicates that the Innes trap has rotated down to the north. This is consistent with northward thickening of the Tertiary section into the evolving Central Graben. The question remains as to what happened to the oil that once occupied the Innes area. Given that both Argyll/Ardmore and Duncan are updip of Innes then it is quite possible these fields received the spilling oil from a proto-Innes Field.

The base of the Rotliegend sandstone in well 30/24-24 was just above the top of the Rotliegend sandstones in well 30/24-27. The RFT data from the two wells was used to estimate an OWC at 12,385 ftSS.

In June 1984 an extended well test was carried out on 30/24-24. This EWT showed some depletion, however it was decided to proceed with developing Innes. By this time the oil in place within Innes had been calculated by HOC (unpublished, cessation of production document, 1991) to be 24.2 mmbbl using a combination of gross rock volume calculated using maps created from 2D seismic data together with the reservoir property and oil-water contact information detailed below. This oil in place figure is higher than reported by Robson (1991) of 19 mmbbl. The origin of the difference between the published and cessation of production figures for STOIIP is not known. The 3D seismic survey acquired over part of the Argyll Field and the northern part of Block 30/24 in 1990 was not interpreted over the known fields including Innes. The aim of the survey was to be able to demonstrate to the licensing authority that there was no remaining exploration prospectivity on the block so that the Argyll, Duncan and Innes fields could be abandoned. The most recent calculation of oil in place was by Tuscan and Acorn in 2003 and was based upon the reprocessed (TU03) 3D seismic dataset (P90 19.7, P50 26.6, P10 34.6 mmbbl).

Regional Context

Block 30/24 lies at the southern end and on the western margin of the North Sea's Central Trough. It differs from the core of the Central Trough insofar as the Mesozoic section is significantly thinned; the Triassic is thin or absent, the Jurassic only represented by the Upper Jurassic (sandstones and shales) and this too may be absent as may be the Lower Cretaceous and a depositionally thin Upper Cretaceous Chalk. Most of the thermal subsidence occurred in the

Tertiary which may comprise 3000+ meters of mostly mudstone (Tang et al, 2018).

The area of Block 30/24 along with contiguous blocks to the north west and south east essentially occupies what was the rift shoulder for the Central Trough. The main reservoirs are Palaeozoic in age with subordinate Mesozoic age reservoirs (Table 1).

The seal horizons in the area are not easily defined. For the two largest fields, Auk and Argyll, the seals are composite comprising Triassic mudstones, tight Chalk and possibly Tertiary mudstones (Trewin et al, 2003; Gluyas et al, 2005). Parts of both fields are also fault sealed. Both Auk and Argyll also contain oil saturated intervals within the Chalk. F-Block fields (Fergus, Flora, Fife and Angus) also rely upon sealing at the base (upper) Cretaceous by tight Chalk (Shepherd et al, 2003; Hayward et al, 2003). However, the Chalk above both Flora and Fife is oil bearing at the Tor interval from which oil has been flowed to surface albeit at modest rates (Megson and Hardman, 2001). Innes has a combined seal of Kupferschiefer (4ft thick mudstone) and Zechstein mudstones and carbonates (60-116 ft thick). This contrasts with the Zechstein interval being a highly productive reservoir in both Auk and Argyll where it is karstified, brecciated and fractures.

The Upper Jurassic Kimmeridge Clay Formation in the adjacent Central Graben is mature for oil over much of the area immediately east of the rift shoulder, with a few deeper pockets mature for gas (Evans et al, 2003). The occurrence of yellow fluorescing, dark oil stain in the sandstones of 30/24-27 and white fluorescence but an absence of oil stain in the sandstones of Innes discovery well 30/24-24 is taken as evidence for two phases for oil migration.

The chronostratigraphy of both reservoir and overburden at Innes is shown in Figure 3.

Database

Robson (1991) reports that over 3000 km of 2D seismic data were available across Block 30/24 by the time that the discovery well was drilled on Innes (30/24-24). In particular, surveys shot in 1980, 1981 and 1982 were used to define the prospect 14 km NW of Argyll which ultimately became Innes. It was not until 1991 that HOC shot a 3D seismic survey across 30/24 (HB91, Figure 4). Incredibly, HOC and the company that acquired them, BHP, never drilled a well on the basis of that survey. Indeed, the survey only partially covered the Argyll and Duncan fields although it did cover the whole of Innes. The survey was processed and interpreted from which a number of prospects and lead were identified. Several of these were close to Innes (Figure 5). However, it is clear from reading the internal HOC documentation which was gained by Tuscan and Acorn when these companies acquired the 30/24 license, the purpose of the 3D seismic acquisition programme was not to define and drill wells but rather to be able to demonstrate to the licensing authorities that there were no commercially viable exploration targets. The seismic data were essentially acquired to enable cessation of production from Argyll, Duncan and Innes. That plan succeeded.

Ultimately, the HB91 3D seismic survey was merged with an Agip survey (AG93, Figure 4) and reprocessed in 2003 to become TU03. It was this reprocessed data together with the five local wells, 30/24-24, 27, 32, 35 and 36 that became the database for the Tuscan/Acorn re-evaluation of Innes in 2003.

All wells in the Innes area (30/24-24, 27, 32, 35 and 36) were drilled between 1983 and 1986 using water-based mud and the wore-line logs suites collected typical of their time and included gamma ray logs (the natural gamma ray tool was used in 30/24-27 only), litho density log, borehole compensated sonic and compensated neutron log for lithology and porosity. The dual induction laterolog was used for resistivity measurements and repeat formation tester for pressure data. All five wells were cored while in the discovery well, 30/24-24 the high-density dipmeter tool was also used. The cores were sampled for porosity and permeability but no special core analysis data (SCAL) have been found for Innes.

Trap

The Innes Field comprises a single tilted fault block. Faults close the structure to the west and south while dip closure occurs to the north and east. The overall geometry of the pool is kite shaped with a long axis of about 2.5 km and shorter axis of 1.5 km. The geometry of the mapped trap did not change appreciably between mapping the structure with 2D seismic data and the revised map following acquisition of 3D seismic data (Figure 2). However, there are fewer faults on maps generated using the 3D data compared with those created by Hamilton geoscientists using the 2D seismic data. We have not found documentation from the Hamilton era to explain the high density of faults mapped from the 2D data. Whilst the NW-SE faults were confirmed by the 3D and were able to be mapped in more detail, it became clear that the NW-SE faults that compartmentalised the structure were not so apparent in the 3D seismic interpretation (and that the formation pressure data in well -32 drilled after start of production from well -24 confirmed that there was good pressure communication between the 2 well locations); and that the fault blocks 2-3 SE of well -24 on the 2D map, which were not considered part of the field in reality probably are, so adding to the STOOIP originally calculated by HOC. It is also clear from the 3D seismic data that a another undrilled near identical structure occurs in the fault block immediately south of Innes (Figure 2).

Reservoir and Petrophysics

The reservoir in Innes is entirely within the Lower Permian Rotliegend Auk Formation sandstones (Heward et al, 2003). Four facies associations are present within the Auk Formation reservoirs of the wells and fields of Block 30/24: aeolian slipface sandstones, aeolian wind-ripple sandstones, water-lain Weissliegend sandstones and other water-lain conglomerates, breccias and sandstones (Figure 6). Five reservoir zones were defined in Innes (Heward et al op cit) and they consist of different proportions of these facies which infill topography and onlap the Argyll High. Fewer zones and an appreciably thinner sequence occurs on the Argyll High itself while at Innes the Rotliegend sandstone thickness is between 68m and 91m. At Innes (wells 24 and 32) the reservoir section comprises more or less equal thirds of water lain sandstones at the base overlain by dune slip-face sandstones that are in-turn overlain by the resedimented Weissliegend Sandstones. Short intervals of wind-ripple sandstones occur interbedded with the dune slip-face sandstones (Heward et al, 2003). The reservoir section at 30/24-27 differs somewhat. The Weissliegend and basal water lain sandstones are thin and the aeolian sandstones are dominated by wind ripple deposits (Figure 7). The distribution and character of the facies reflect periods of sediment supply, subsidence and fluctuating climatic conditions towards the margin of the Northern Permian Basin..

The Auk Formation as a whole forms a high quality reservoir at depths of 3000–4000 m. The best intervals, with Darcy permeabilities, consist of coarse-grained Weissliegend sandstones and due slipface sandstones (Figure 8). The porosity and permeability of both water leg and oil leg sandstones are comparable and there is little mineral cement in the sandstones despite a reservoir temperature of 145°C. Heward et al (op cit) suggested that the absence of significant cementation resulted from the fact that significant burial of the area occurred only since the beginning of the Tertiary.

Oil in place

The oldest oil in place figure we have found for Innes is 19 mmbbl published by Robson (1991) and presumably pre-dating a figure of 24.2 mmbbl that was recorded in the end of year (1991) cessation of production report by HOC and submitted to the licensing authority. Tuscan and Acorn remapped the Innes Field using the TU03, 3D seismic dataset. The P90 oil in place was calculated to be 19.7, P50 26.6 and P10 34.6 mmbbl.

Production History and Reserves

In January 1985, after the Deep Sea Pioneer (DSP) was installed on Argyll, the original production vessel from Argyll, the Trans World 58 (TW58) was moved to well 30/24-24 and production started. The oil was processed on the TW58 and stabilized crude oil was exported to the Argyll base manifold and hence to the mooring buoy and shuttle tanker. Well 30/24-32, located about 1 km north-west of well 30/24-24, was tied into the production facilities in November 1985. The summed peak production from the two was around 10,000 stb/d but both wells declined rapidly and the average production for the two wells combined (including downtime) was never more than 6000 stb/d (Figure 9).

In January 1986 well 30/24-35 was drilled to develop the south-east part of the structure. However this well found the top Rotliegend sandstones at 12,442 ft sub-sea, almost 300 ft deeper than prognosed, and the entire Permian section was water saturated. Well 30/24-35 was plugged and abandoned.

The rapid decline in production rates, coupled with the relatively high operating costs of using the TW58 floating production facility, meant that field life would be very limited. HOC carried out a feasibility study into changing the production system from a dedicated floating production facility (FPF) to a subsea satellite tied back to a remote FPF. The objective was to remove the TW58 and produce Innes directly to the DSP. However several issues / problems (eg. flow instability, wax, hydrates, corrosion) were anticipated and while technical solutions existed the project economics would not stand the additional costs.

HOC decided to run a field trial producing Innes to the DSP, by-passing the separation facilities on the TW58. The trial was carried out from 17th Aug – 26th September 1986. The Innes wells were successfully flowed to the DSP both independently and commingled. This subsea tie-back achieved 80% of the production rate obtained using the TW58. The subsea flowline introduced a differential pressure of 200 – 400 psi. A few problems due to gas hydrates and cold fluids in the DSP process plant were identified, however these issues were manageable. HOC concluded that Innes could be permanently tied back to the DSP.

HOC installed a new subsea manifold at well 30/24-24 and ran subsea control umbilicals from the DSP to the Innes wells. The TW58 was demobilized on 31st Dec 1986 and the tie-back project was completed on 9th Jan 1987, just 15 weeks after the end of the field trial.

In December 1990 a severe storm shut in the field. In early 1991 HOC were unable to resume flow from either of the production wells because the downhole safety valves were closed and they were unable to reset them. Workovers on both wells were carried out however they were unsuccessful. A record of why the wells were worked over when the flow rates prior to the storm had been so low (well 32 more or less ceased production and well 24 producing about 100 stb/d) has not been found. It could be that HOC were more interested in the solution gas form Innes for effecting gas lift on Argyll Field wells.

Innes contains light oil (45° API) with a high GOR (1700 scf/stb). Saturation pressure is around 4100 psia. The initial reservoir pressure was 6589 psia at 12,322 ft tvdss; this is around 1000 psi over-pressured.

The Innes Field was produced via primary pressure depletion (exsolution gas drive) with minor aquifer support from two wells (30/24-24 and 30/24–32). Both wells showed similar production trends (Figure 9): a rapid decline in production rate over the first 1 – 2 years followed by a more gradual decline in the rate for the remaining 2 – 4 years. Very little water was produced by either well – the final water cut for well 30/24-32 was less than 10% and for well 30/24-24 it was only about 2%. Both gas and oil were exported to Argyll by pipeline and the gas from Innes used for gas lift on Argyll Field wells.

The observed field gas-oil ratio (GOR) was quite variable (1300 – 2300 scf/stb) but did not show a consistent increasing trend (Figure 9). It appears that the reservoir pressure fell below the saturation pressure in 1986 – 87 (Table 2). The GOR did not appear to rise over the final 3 – 4 years of production. This may be due to inaccuracies in the GOR measurements, the PVT properties or the formation of a secondary gas cap.

The reservoir pressure data indicates some support after the initial rapid pressure decline (Fig. 10).

The RFT data from all the Innes wells is shown in Figure 11. Wells 30/24-32 and 30/24–35 were drilled after the start of field production. Well 30/24-32 is in good communication with production well 30/24-24, whereas 30/24-35 has limited communication. The differential pressures within the Rotliegend sandstone interval seen in both these RFTs indicate that significant baffles (sabkha mudstones) to vertical flow are present and that principle production was from the uppermost Weisliegend sandstones (Heward et al, 2003).

It is interesting to note that well 30/24-27 is quite close to well 30/24-35 where the RFT showed poor communication with well 30/24-24. It is possible that the two wells (24 & 27) that were used to define the OWC from RFT data may have a barrier between them and may be in slightly different pressure regimes. It is possible that the OWC of 12,385 ft sub-sea is not correct. A deeper OWC would certainly help explain the lack of water production.

It seems anomalous that 5.8 mmstb were produced from Innes with only minor amounts of water and no increase in the GOR. The production history data and / or the reservoir description may not be correct. It is quite possible that the STOOIP is greater than the 24 mmstb calculated by HOC and closer to the P10 case of 34.4 mmbbl calculated by Tuscan and Acorn.

Further production from Innes is very dependent upon either natural pressure recharge or providing pressure support. Given the extensive nature of the Rotliegend sandstones reservoir (Heward et al, 2003) it is quite likely that significant natural pressure recharge has occurred. Neither of the production wells were located at the crest of the structure. It is difficult to estimate future potential, however with a couple of wells and the right production system a further 5 – 10 mmstb, perhaps more, may now be recoverable. Experience gained from the redevelopment of Argyll as Ardmore demonstrated that moderate to high angle wells with modern completions including electro-submersible pumps could deliver well with significantly higher production rates and sustainable production than was the case with wells drilled in the 1979s and 1980s (Gluyas, et al, 2018).

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Field Summary Table

See separate file

Table 1 Discoveries and Fields in the area around the Innes Field

Field name	Block	Date of discovery	Reservoir age	Reservoir	Fluid type
Auk	30/16	February 1971	Permian	Zechstein, Rotliegend	Oil
Auk North (beyond drilling radius of Auk platform)	30/16	September 2007	Permian	Rotliegend	Oil
Innes	30/24	April 1983	Permian	Rotliegend	Oil

Duncan (Galia)	30/24	January 1981	Jurassic	Fulmar	Oil
Argyll (Ardmore, Alma)	30/24, 30/25	August 1971	Cretaceous, Jurassic, Permian, Devonian	Chalk (untested), Fulmar, Zechstein, Rotliegend Buchan	Oil
30/25-4 discovery	30/25	October 1988	Permian, Devonian	Rotliegend Buchan	Oil
Iris discovery	30/29	March 1980	Jurassic	Fulmar	
Angus	31/26, 30/26	March 1983	Jurassic	Fulmar	Oil
Flora	31/26	August 1997	Cretaceous, Carboniferous	Chalk (tested, unproduced), Flora	Oil
Fife	31/26, 31/27, 39/1, 39/2	April 1991	Cretaceous, Jurassic	Chalk (tested, unproduced), Fulmar	Oil

Fergus	39/2	October 1994	Jurassic	Fulmar	Oil

Table 2 Innes Field pressure data

Date	Well	Event	Reservoir pressure (psia at 12,322 ftSS)	Cumulative oil production (mmstb)
Mar 1983	24	RFT	6,589	0
Jun 1984	24	Test	6,547	0.028
Apr 1985	24	Survey	6,067	0.320
Aug 1985	32	RFT	5,323	0.881
Sept 1985	32	Test	5,185	0.985
May 1986	24	Survey	4,052	2.275
Aug 1986	24	Survey	3,662	2.853
Sept 1986	24	Survey	3,615	2.900
*Feb 1991	32	Survey	**2,500	5.754
* estimated date, ** gauge not at perforations				

Figure captions

Figure 1 Regional location map for the Innes (Block 30/24) and surrounding fields. The main Upper Jurassic basin domains are also shown.

Figure 2 Innes Field maps: A. 1991 map based upon interpretation of 2D seismic data (Robson, 1991) and B. 2003 map based upon interpretation of 3D seismic data. Maps are to the same scale. Map B. also shows adjacent South Innes prospect as mapped in 2003. The mapped surface is Top Rotliegend Sandstone.

Figure 3 Chronostratigraphic chart for Block 30/24 and adjacent areas.

Figure 4 Area covered by the first 3D seismic surveys over Block 30/24 (HB91 = Hamilton 'Argyll' 3D seismic survey 1991; AG93 = Agip 'Iris' 3D seismic survey 1993). The two volumes were merged and reprocessed in 2003 to become TU03.

Figure 5 Prospects and leads map taken from HOC Technical Committee Meeting notes of 1st December 1997.

Figure 6 Auk Formation facies associations at Innes: a. aeolian facies associations, vertical well 30/24-27, dips are approximately depositional. Steeper dips in dune, slip-face, grain flow sandstones are overlain and underlain by more gently dipping mm-thick, wind ripple, laminated apron and dry interdune sandstones, BS = bounding surface. b. water-lain Weissliegend facies, two thin, wind-ripple, laminated aeolian sandstones (arrowed) within massive, coarse to medium grained Weissliegend sandstones (core from deviated well 30/24-32 at 27°). c. matrix supported breccia, containing angular clasts of fossiliferous Middle Devonian dolomites (Kyle Group). Photographs reproduced from Heward et al, 2003.

Figure 7 West to east log panel across the Innes Field showing the character and distribution of the Rotiegend deposits. The five reservoir zones are best developed in 3024-27 and 32 (from Heward et al, 2003).

Figure 8 Auk Formation reservoir properties, Innes Field and adjacent wells (30/24-24, 27, 32, 35) and wells (from Heward et al, 2003).

Figure 9 Innes Field production and GOR profiles.

Figure 10 Innes pressure history as a function of (A) date and (B) cumulative oil production (pressures reported at field datum 12,322 ft TVDSS). Field start-up was January 1985.

Figure 11 Comparative RFT data from the Innes Field and surrounding wells. Well 30/24-7 is an exploration well located midway between Argyll and Innes.

(Parameter)	(Data and suggested Units)	(Author's explanatory comments)
Trap		
Type	Tilted fault block	
Depth to crest	12,000 (ft TVDSS)	
Hydrocarbon contacts	12,385 (ft TVDSS)	OWC inferred from RFT data
Maximum oil column thickness	385 (ft)	Absence of water production indicates OWC may be deeper
Maximum gas column thickness	Not applicable (ft)	
Main Pay Zone		
Formation	Auk Formation	Rotliegend sandstone
Age	Lower Permian	
Depositional setting	Terrestrial – alluvial fan at base, overlain by erg and erg margin, water reworked uppermost interval.	
Gross/net thickness	max thickness 300ft	The Rotliegend sandstones infill topography; thickness range 151-300ft (Heward et al, 2003)
Average porosity (range)	16.8% (5-29%)	
Average net:gross ratio	0.82	
Cutoff for net reservoir	10 mD	As used by Hamilton
Average permeability (range)	Arithmetic 421 mD, geometric 63 mD (0.1-7,000mD)	
Average hydrocarbon saturation	54%	
Productivity index range		
Hydrocarbons		
Oil gravity	45 (°API)	
Oil properties		Slight waxing tendency
Bubble point (oil) Dew point (condensate)	4100 psig	Saturation pressure
Gas/Oil Ratio or Condensate/Gas Ratio	Approx.1700 scf/bbl	
Formation Volume Factor (oil)	2.03	
Gas gravity	n/a	
Gas Expansion Factor	n/a	
Formation Water		
Salinity	80,000 (ppm NaCl equiv.)	
Resistivity	0.024 ohm-m at 300F	
Pressure gradient - water	0.45 psi ft^{-1}	
Reservoir Conditions		

Temperature	146 (°C)	295°F
Initial pressure	6589 (psia at 12,322 ft TVDSS)	
Hydrocarbon pressure gradient - oil	(psi/ft)	
Hydrocarbon pressure gradient - gas	(psi/ft)	
Field Size		
Area	2.25 (km^2)	2004 evaluation based on 3D seismic
Gross Rock Volume	99,136 (ac-ft)	
STOOIP	24.2 (mmbbl)	
Associated GIP	Not calculated (bcf)	
Non-associated GIP	Not calculated (bcf)	
Drive mechanism (primary, secondary)	Primary pressure depletion	Some natural pressure support noted, likely aquifer inflow
Recovery to date - oil	5.8 (mmbbl)	
Recovery to date - gas	9.8 (bcf)	The produced gas contained 18-25ppm H_2S
Expected ultimate recovery factor/volume - oil	24 (%)/ 5.8 (mmbbl)	
Expected ultimate recovery factor/volume - gas	(%)/(bcf)	
Production		
Start-up date	1985	
Number of Exploration/Appraisal Wells	1/4	
Number of Production Wells	2	Exploration well and one production well used for production
Number of Injection Wells	0	
Development scheme	Sub-sea tie back to Argyll Field	
Plateau rates – oil/gas	6000 bopd 10.8 mmcfgd	Plateau production lasted about 6 months
Planned abandonment	October 1992	Production ceased on Innes in 1990 following a storm. It was never restarted

Innes Figure 1
Location map

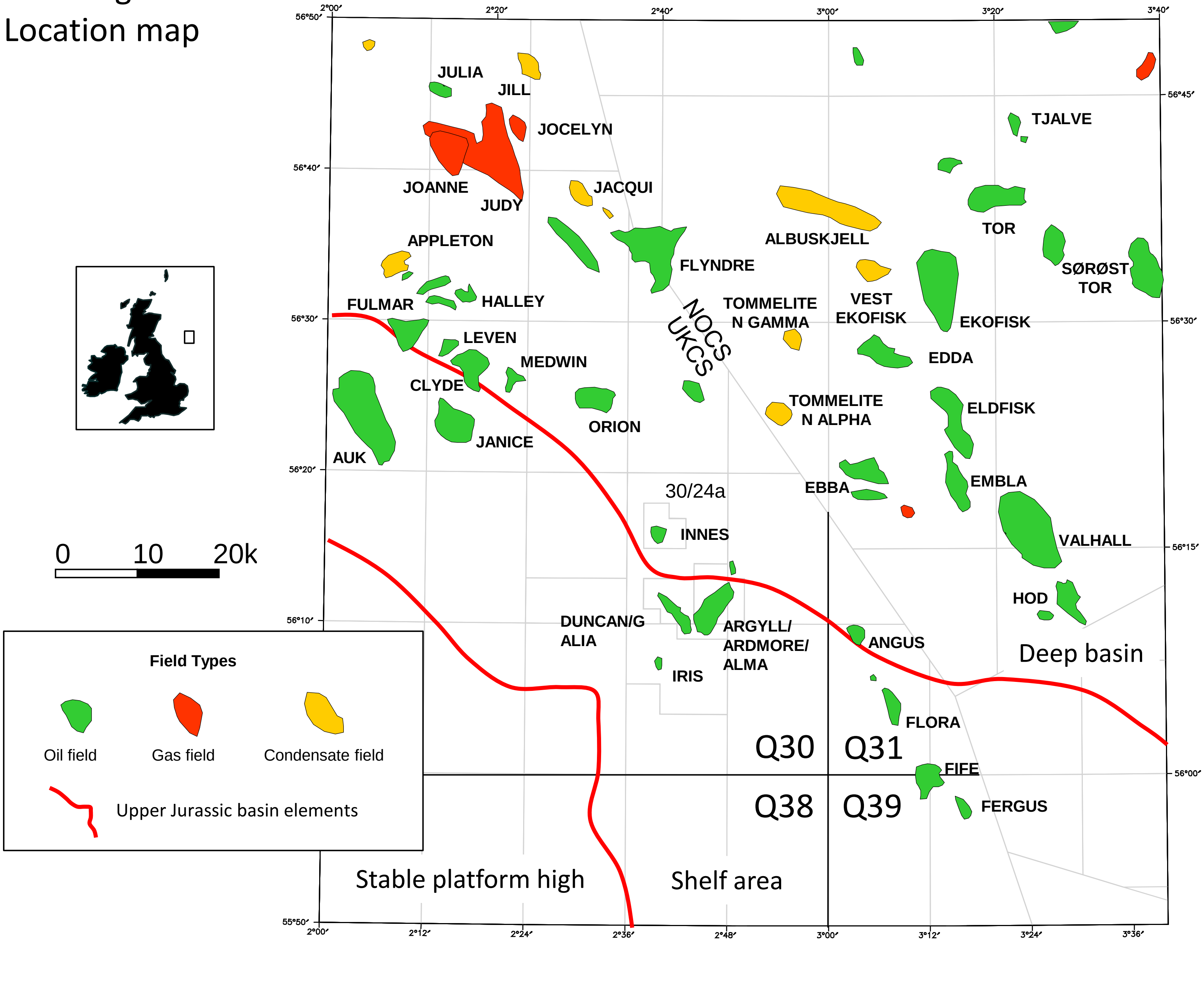
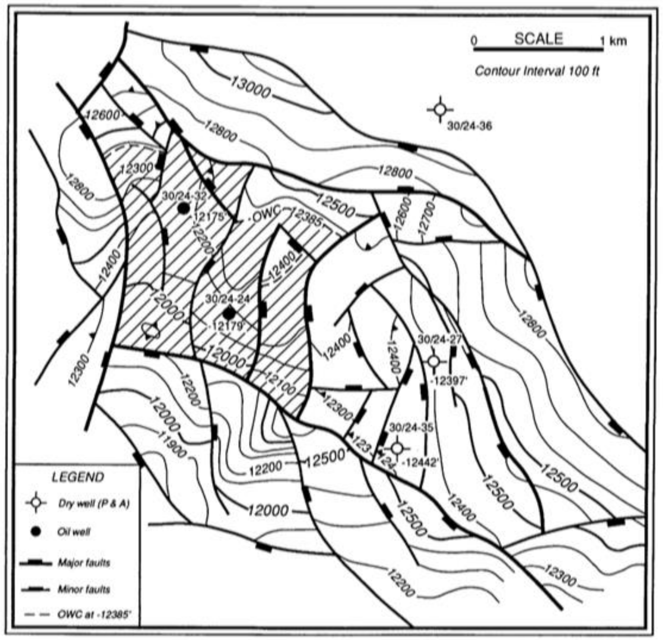
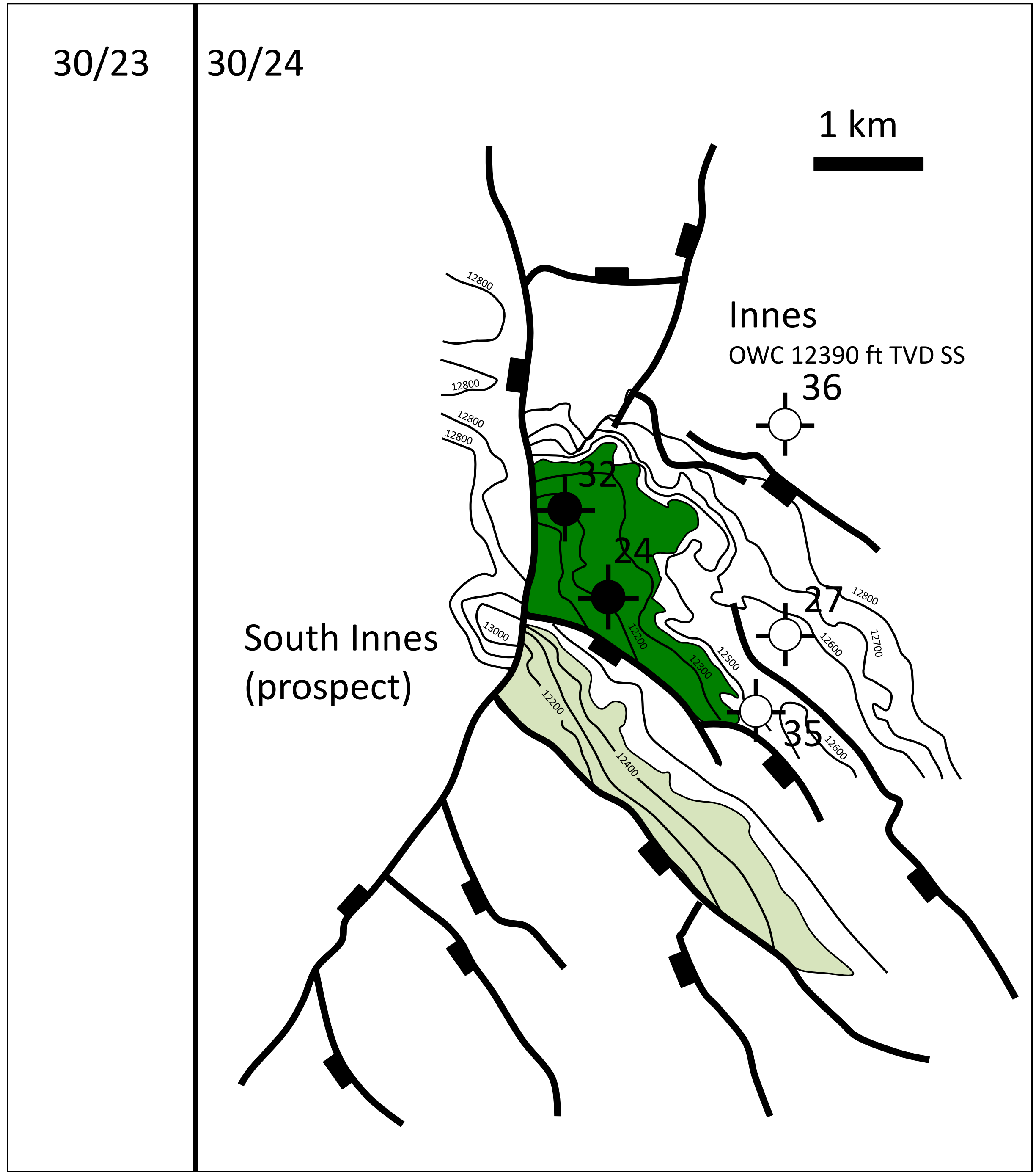


Figure 2 Innes maps

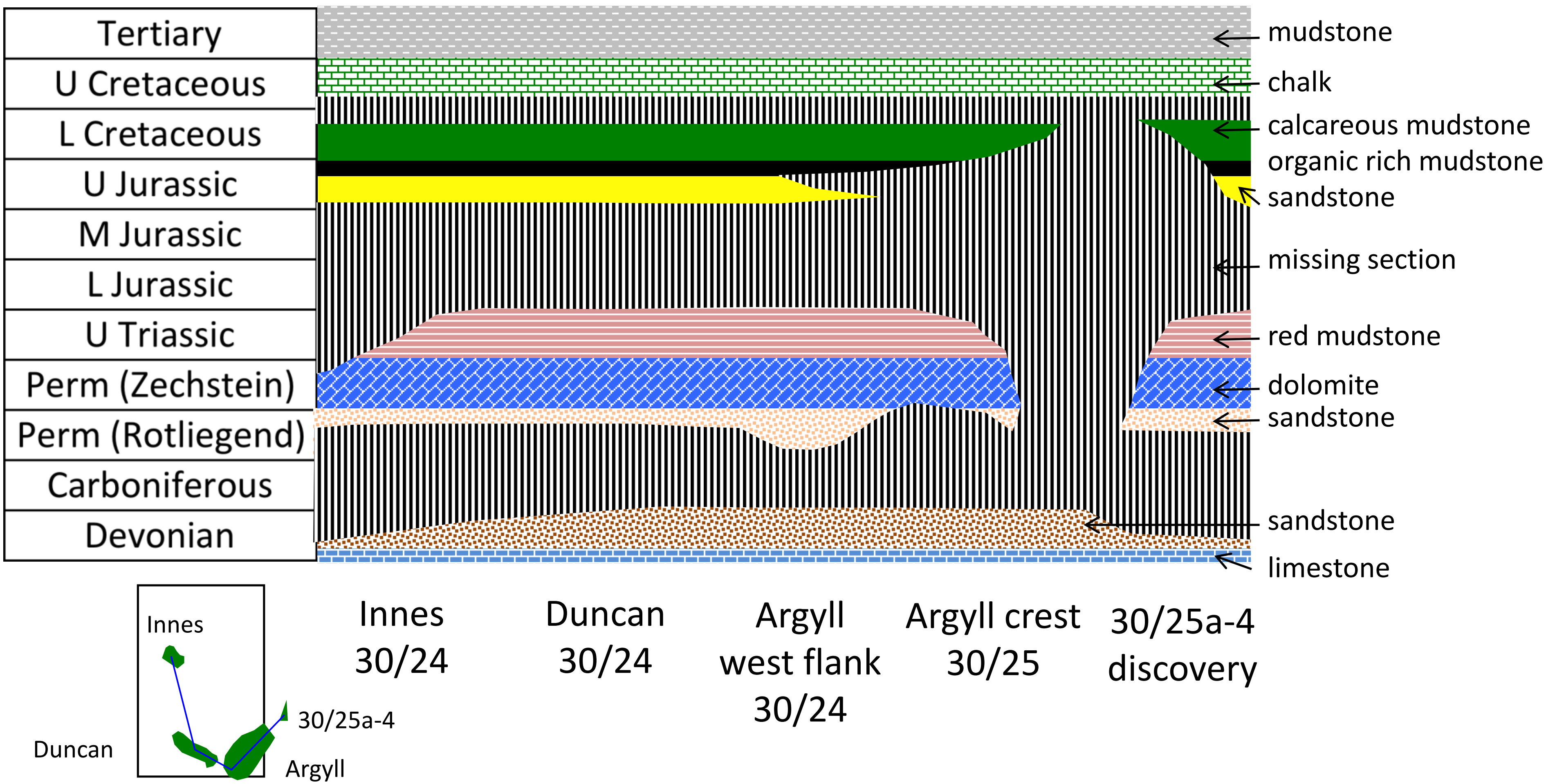


A

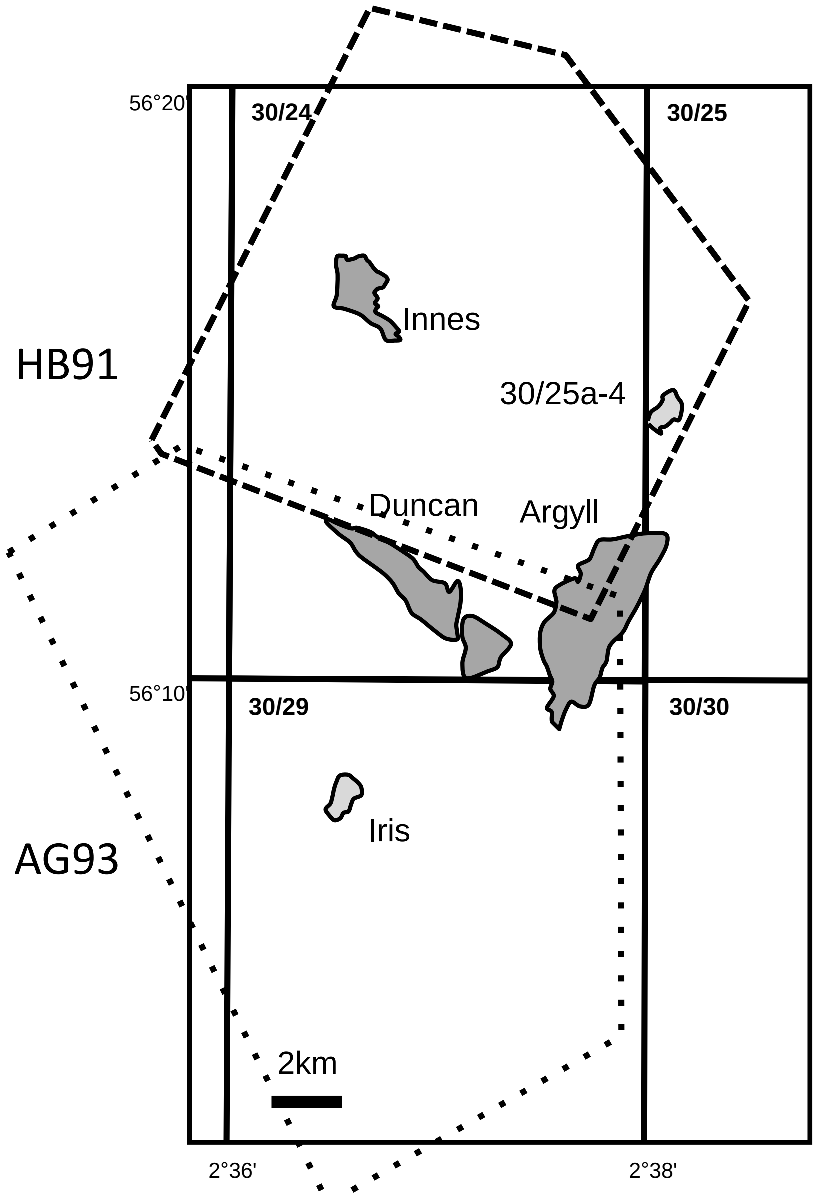


B

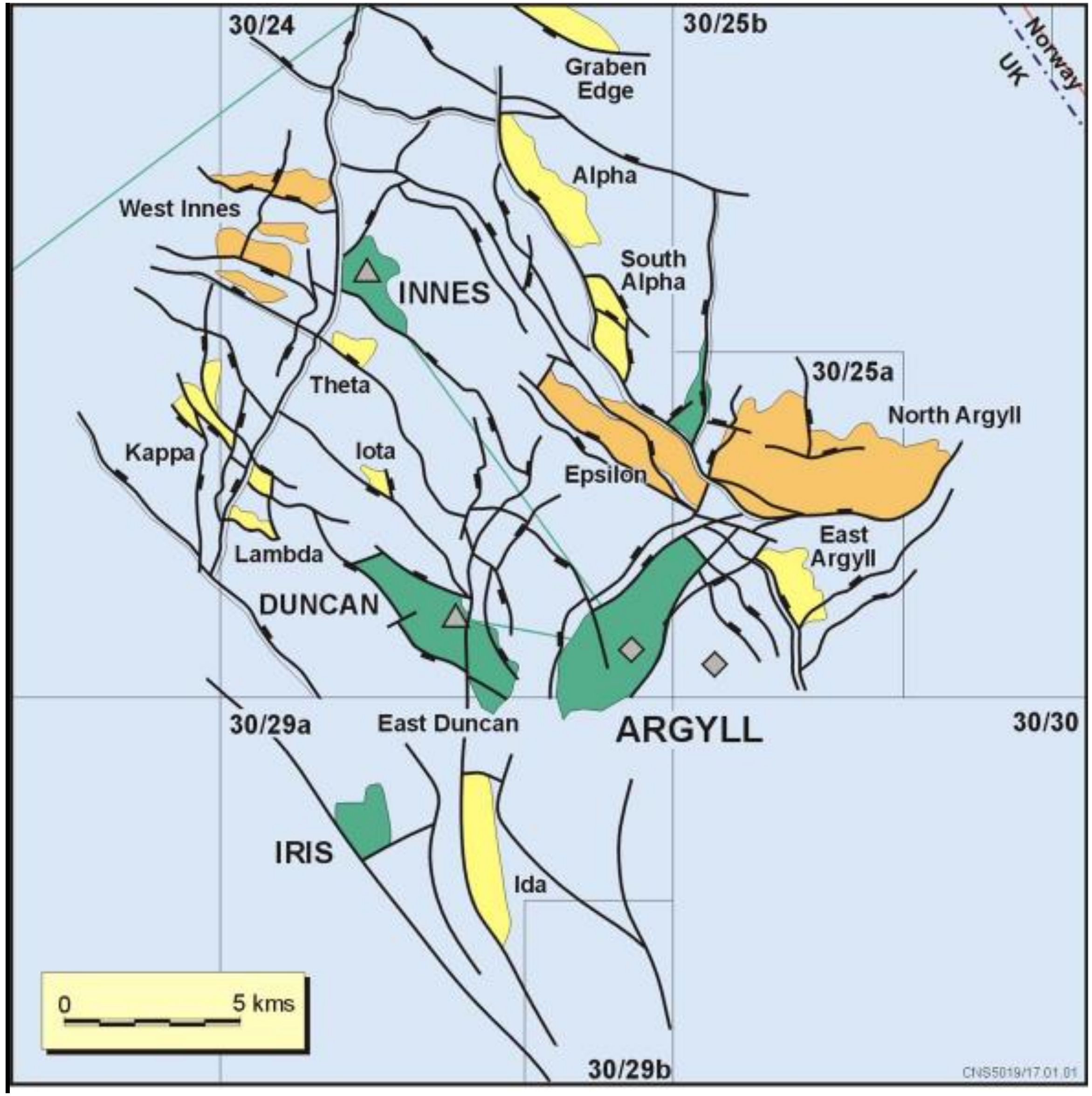
Innes Figure 3 stratigraphy



Innes
Figure 4
3D
seismic

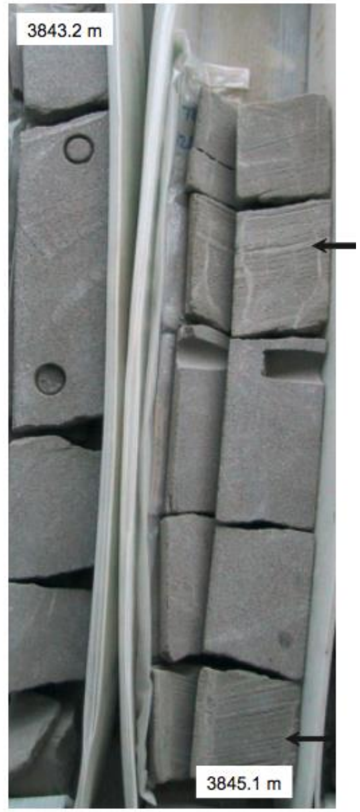


Innes Figure 5 Prospectivity



Innes Figure 6 facies

a. 30/24-27



b. 30/24-32

c. 30/24-32

Innes Figure 7 reservoir correlation

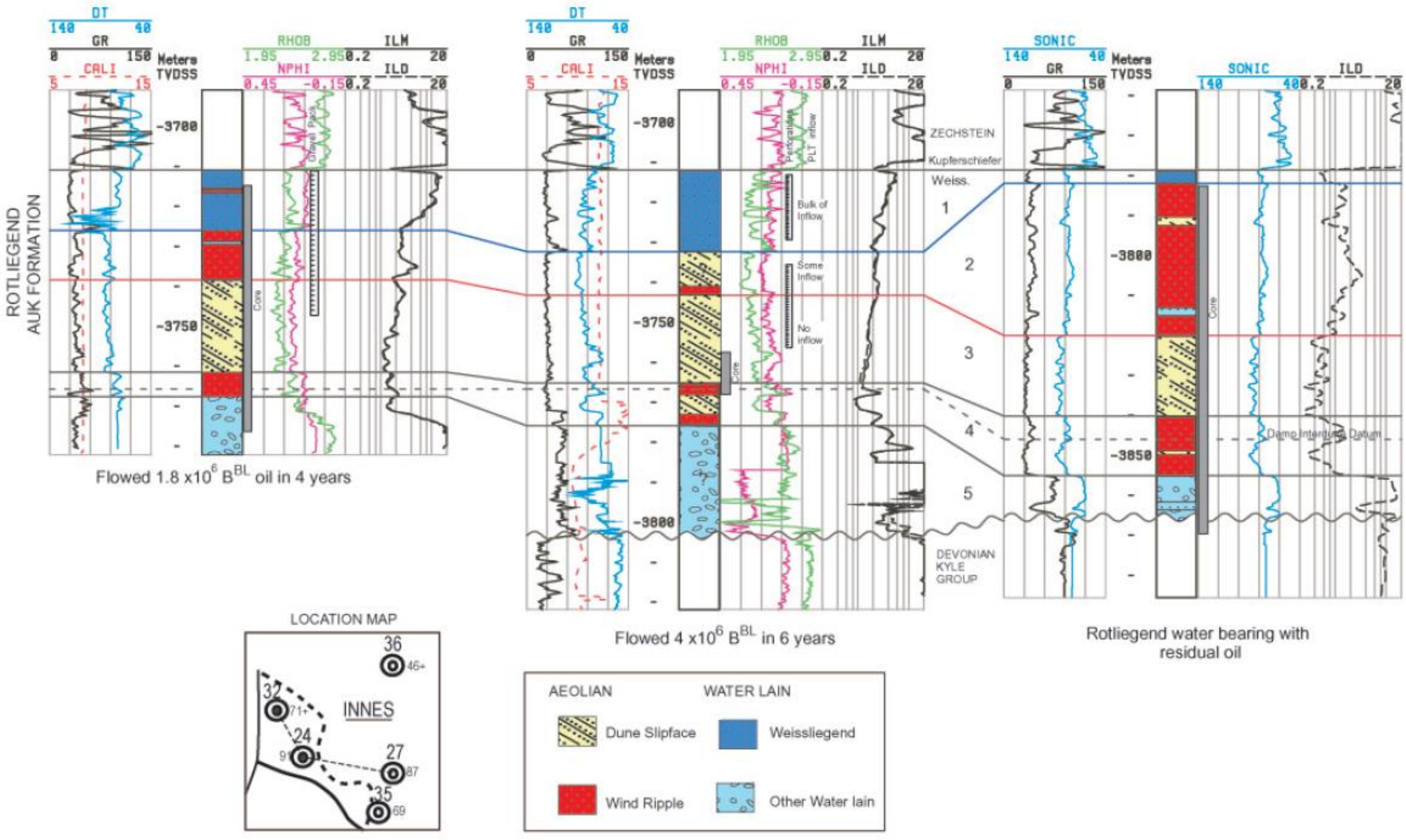
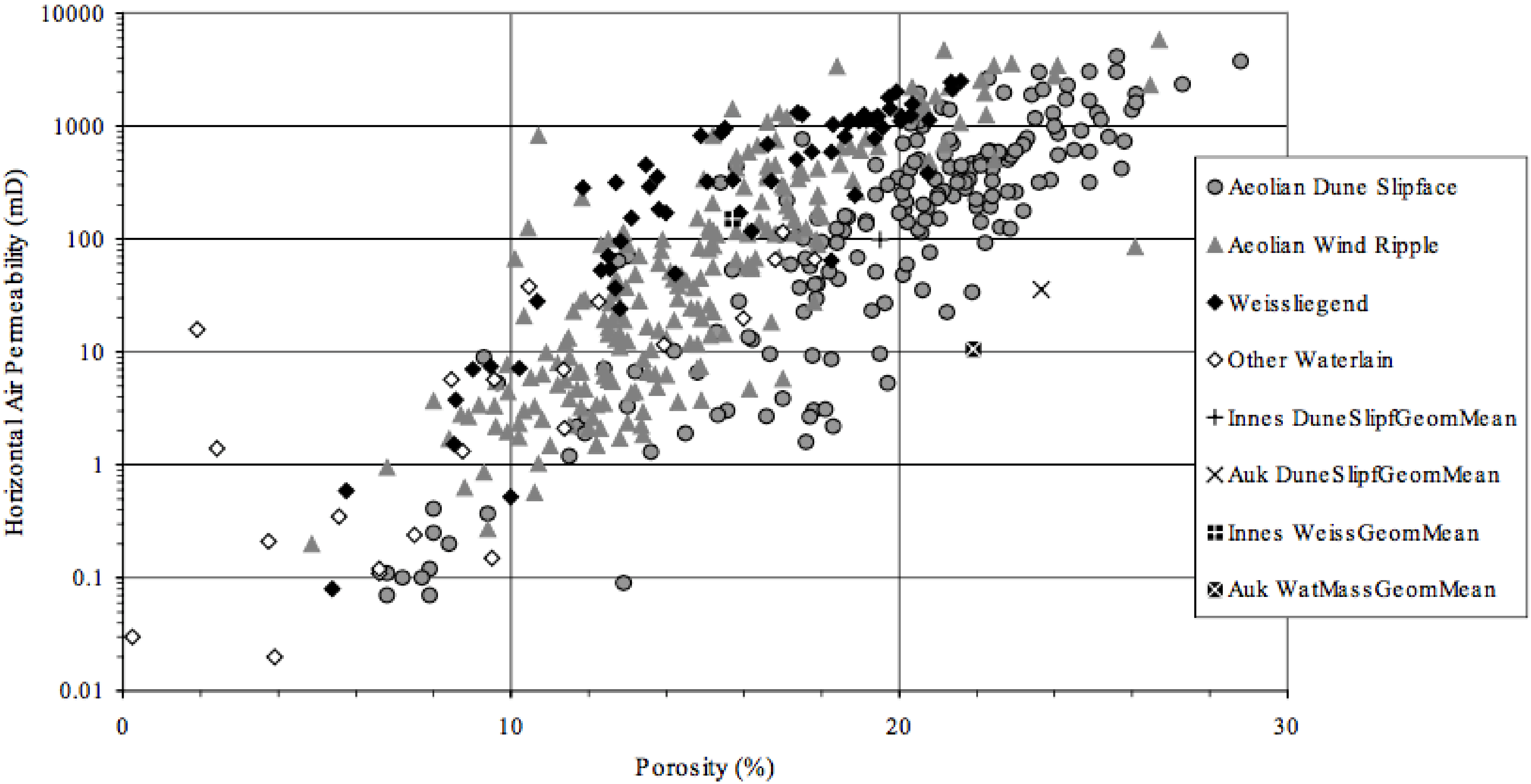


Fig. 7. West to east log panel across the Innes Field showing the character and distribution of Rotliegend deposits. The five reservoir zones are most clearly evident in wells 30/24-27 and -32 that are extensively cored. The base of the Rotliegend does not appear to have been penetrated in well 30/24-32 and may occur in the interval above what is clearly *in situ* Devonian Kyle Group carbonates at the base of 30/24-24. Key to wireline logs as Figure 6

Innes Figure 8 Reservoir quality



Innes Figure 9 Production data

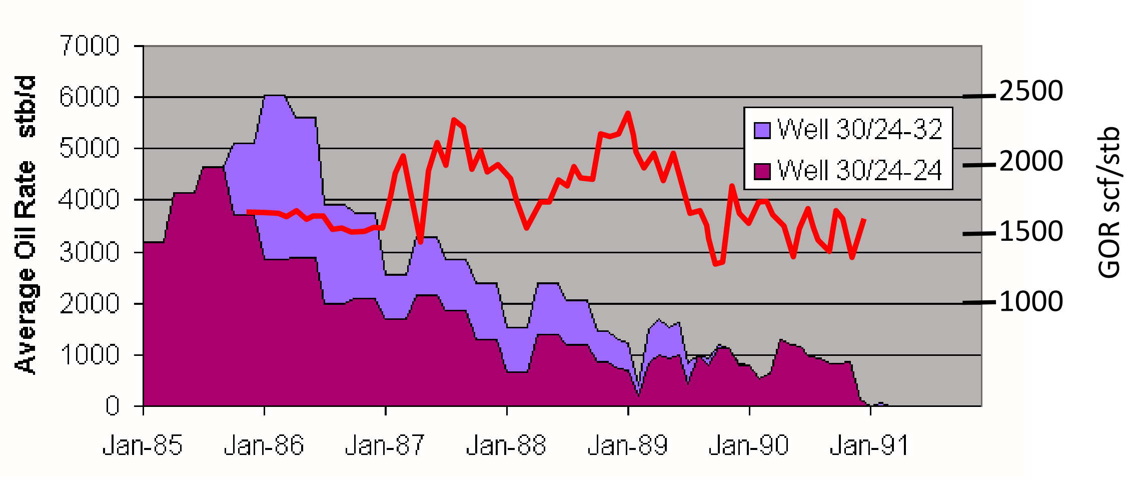
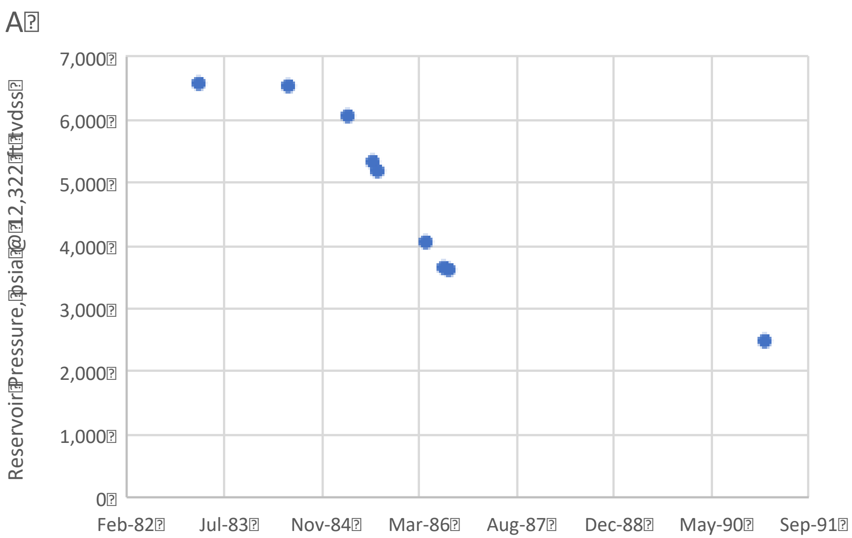
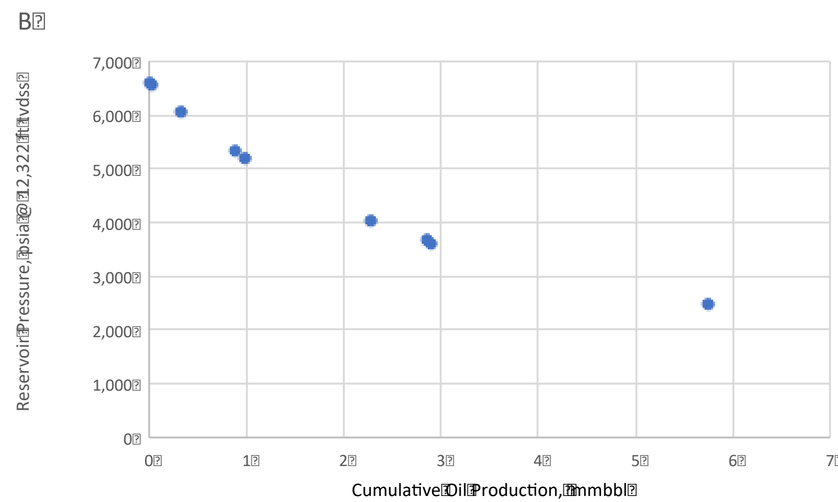


Fig. 10 - Inness Pressure History





Innes Figure 11 RFT data